Docket:	:	A.08-02-001
Exhibit Number	:	DRA-3
Commissioner	:	Simon
ALJ	:	Wong
Witness	:	Sabino

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Application of San Diego Gas & Electric and Southern California Gas Company Biennial Cost Allocation Proceeding Phase II

Cost Allocation Issues SoCalGas

San Francisco, California
November 21, 2008

363468

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Southern California Gas Company
Cost Allocation Issues

I. INTRODUCTION

Pursuant to Phase Two scope of issues in Commissioner Simon and Administrative Law Judge ("ALJ") Wong's Ruling dated April 17, 2008 in Application (A.)08-02-001, this exhibit presents the Division of Ratepayer Advocates' ("DRA") analyses and recommendations regarding Southern California Gas Company's ("SoCalGas") proposal on "whether the updated cost allocations and rates are just and reasonable and should be adopted."[1] In this application, SoCalGas proposes to abandon the current Commission-adopted Long Run Marginal Cost ("LRMC") New Customer Only ("NCO" or collectively referred to as "LRMC/NCO") cost allocation methodology for its natural gas transportation base margin costs. SoCalGas instead proposes that the Commission adopt the Embedded Cost ("EC") methodology for the cost allocation of its base margin in lieu of the Commission-adopted LRMC/NCO methodology. SoCalGas has submitted rate designs for both an LRMC-based and an EC-based cost allocation. SoCalGas proposes the EC-based cost allocation as the "preferred" methodology, while it offers the LRMC-based methodology Rental method (collectively referred to as LRMC/Rental) as a "compliance" case only. The Commission has already determined that LRMC/NCO results in just and reasonable rates in D.00-04-060. Compared to the LRMC/NCO cost allocation approach, the proposed EC-based cost allocation approach is not just and reasonable for many reasons for SoCalGas, including that it will improperly allocate a greater share of the SoCalGas base margin to core customers, resulting in higher rates for SoCalGas' core customers. In this testimony, DRA provides its recommendations on the cost allocation methodology for SoCalGas' base margin to its different customer classes.

The Commission first adopted the LRMC methodology for California gas utilities in D.92-12-058. Through the years, the Commission affirmed its preference

[1] See Ruling, p. 7.

for the LRMC methodology in several other subsequent cost allocation decisions in proceedings before the Commission for both gas utilities and electric utilities.[2] In D.00-04-060, the decision adopted the current LRMC/NCO cost allocation approach when it approved a Joint Recommendation ("JR") of settlement parties in that proceeding. D.00-04-069 states that "the JR would adopt the LRMC/NCO method, which is the current method adopted for PG&E, SDG&E, and SCE, while rejecting the replacement cost adder."[3] For reasons explained in this testimony, DRA continues to support the Commission's preference for LRMC/NCO for SoCalGas as well as the Commission's general guiding principles on cost allocation matters in reaching its conclusions and recommendations. The Commission's cost allocation guidelines focus on the principles of cost incurrence, economic efficiency, and equity as important considerations in selecting the appropriate allocation factors that are both just and reasonable.[4] As established in the past LRMC decisions, the results of both the LRMC and EC cost allocation approaches are ultimately scaled up or down to reconcile with the Commission-approved base margin (or revenue requirement) in the General Rate Case proceeding. The scaling of costs ensures that the utility has the opportunity to recover its authorized base margin.[5]

II. SUMMARY OF RECOMMENDATIONS

In summary, DRA recommends:

- That the Commission retain the adopted LRMC New Customer Only ("NCO") method for the cost allocation of the SoCalGas natural gas transportation base margin. SoCalGas has not demonstrated that either its proposed LRMC/Rental method or its proposed EC method is a more equitable alternative to the current LRMC/NCO method. As DRA explains

[2] See some of these Decisions in (D.) 93-05-066, D.95-12-053, D.96-04-050, D.97-08-055, D.97-04-082, D.97-08-062, D.98-06-073, D.00-04-060, D.01-11-001, and D.05-06-029.

[3] D.00-04-060, p. 8.

[4] See D.86-12-009, D.90-07-055, and D.92-12-058.

[5] See D.92-12-058.

later in this testimony, the LRMC/NCO method recommended by DRA is without any of the replacement cost adders in marginal distribution and customer costs;

- That the Commission adopt the results of the LRMC/NCO cost allocation for the SoCalGas base margin because they are just and reasonable;
- That the Commission direct SoCalGas to modify its compliance filing to actually comply with the current adopted cost allocation methodology of LRMC/NCO;
- That in the alternative, if the Commission were to reject DRA's recommendation to continue to adopt LRMC/NCO for SoCalGas and adopt instead the EC methodology, the Commission must modify components of the proposed EC, as it currently stands. The SoCalGas EC filing assumes 70 Bcf of core storage inventory reservations while the Settlement Agreement ("SA") in Phase I of this proceeding proposes 79 Bcf of core storage inventory reservations. The SA adopts the embedded cost methodology for the SoCalGas/SDG&E gas storage function only.[6] The Commission should allow further consideration of the proposed EC allocation methodology for the remainder of the SoCalGas functions for natural gas base margin transportation costs to customers for the BCAP period 2009 to 2011 subject to SoCalGas modifying certain elements of the proposed embedded cost allocation identified by DRA resulting in a more equitable allocation;
- That the Commission order the update of the proposed cost allocation methods based on the combined core portfolio storage amounts pursuant to a Commission approval of the Settlement Agreement in BCAP Phase 1 of this proceeding;
- That SoCalGas' modifications to the proposed embedded cost method should, at a minimum, provide the same percentage share of cost allocation as the LRMC/NCO shown in this testimony, and include:

- Modifying the Administrative & General (A&G) cost allocation by allocating 50% of A&G costs on the basis of the average year throughput, in particular, on an equal cents per therm basis (ECPT);
- Modifying the allocation of the remaining 50% of A&G costs based on O&M costs by using the Multi-factor, including the functionalization of FERC Accounts 920 (A&G Salaries), 921 (Office Supplies & Expense), 926 (Employee Pensions & Benefits), 931 (Rents), 408 (Payroll taxes), 932 (AdmGen Mnt-General Plant) and 389.1 thru 398 (General Plant depreciation) instead of the Labor Factor, and for the general plant returns and taxes functionalization;
- Updating the service line footage based on the latest 2006 data instead of the 2001 data used in the study;
- Updating the storage functional factors based on the most recent storage cost data consistent with the 2007 FERC Form 2 instead of the previous storage data used that was consistent with the 2006 FERC Form 2;
- Using the Average Year Throughput as the customer class allocator (instead of Cold Year Throughput) for the backbone transmission base margin for purposes of consistency with the allocator of the FAR revenue credits on transmission costs authorized in D.06-12-031 (FAR decision); and
- Using the historical embedded cost of meters represented by SoCalGas' net book value of meters as the customer class allocator (instead of the current purchased costs of meters) for customer-related O&M costs for distribution meters and regulators.

(continued from previous page)
[6] As contemplated in ALJ Wong's PD of November 4, 2008.

DRA's review of the SoCalGas Base Margin, its functionalization, and the cost allocation of these functional categories for the different customer classes yield the following Core/Non-Core splits as summarized below in Tables 1 and 2. Table - 1 is based on a 70 Bcf storage inventory assumption while Table 2 is based on the greater storage assumption of 79 Bcf.[7] The total amount of core storage for the combined core portfolio of SoCalGas and SDG&E that is shown in the LRMC/ Rental Direct Testimony is based on the Omnibus Proposals of 70 Bcf of core inventory, 327 MMcfd of core injection, and 2,225 MMcfd of core withdrawals. Therefore, if the SA is adopted, SoCalGas should update its filing to incorporate the figures in Table 2.

In Table 1, DRA compares its LRMC/NCO recommendation with the SoCalGas "compliance" filing under LRMC/Rental) and the SoCalGas "preferred" filing under EC. The results for the SoCalGas LRMC/Rental column shown in Table 1 include cost allocation for SDG&E's core storage in the amount presented for Total Core. Further, the amount shown for Total NonCore in the SoCalGas LRMC/Rental column includes the cost allocation for Noncore Unbundled storage. Table 1 shows that under the DRA recommended LRMC/NCO approach, SoCalGas core customers will have an 84.8% share of the base margin, while noncore customers will have a 15.2% share of the base margin. Under both the LRMC/Rental and the SoCalGas EC proposals, the SoCalGas core customers will have a greater share of the base margin, at 87.5% and 89.2% of the base margin, respectively. The SoCalGas noncore customers will have a lower share of the base margin, at 12.5% and 10.8% of the base margin, respectively.

In Table 2 shown in the succeeding page, DRA provides the same comparisons but with the LRMC/NCO, LRMC/Rental, and EC results based on the Settlement Agreement in Phase I of this BCAP that provides for 79 Bcf of core inventory, 369 MMcfd of core injection, and 2,225 MMcfd of core withdrawals. The results in Table 2 similarly affirm the results shown in Table 1.

[7] The 79 Bcf is pursuant to the SA pending before the Commission in Phase I of this proceeding A.08-02-001.

In Tables 3 and 4, DRA provides a summary of the results of the cost allocation by function (in $Ms and in %, respectively) for each of the LRMC/NCO, LRMC/Rental, and the EC based on the 70 Bcf core storage reservation.

Table 3 shows what shares of the base margin the three different cost allocation methods would assign by each functional area. For example, in Table 3, the SoCalGas EC proposal would assign the most costs to the customer-related function compared to either LRMC/NCO or rental approaches. Further, Table 3 also shows that the LRMC/NCO approach would assign the most costs to the demand-related portion of distribution function compared to either the LRMC/Rental or the SoCalGas EC proposal.

In Tables 5 and 6, DRA provides the same information based on the 79 Bcf core storage reservations proposed in the Phase I Settlement Agreement. These two tables affirm the results indicated in the prior Tables 3 and 4.

Table 1
Summary Results of SoCalGas Base Margin Allocation Methods

[in $Mn and Percent Share By Customer Class]

Based on 70 Bcf Core Storage

Customer Class	DRA Recom. LRMC (NCO)	DRA As % of Total System	SCG Proposed EC	SCG EC as % of Total System	SCG Proposed LRMC (Rental)	SCG LRMC as % of Total System	Amt SCG EC> DRA	Percent SCG EC> DRA	Amt SCG LRMC>DRA	Percent SCG LRMC>DRA
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Residential	$1,112.9	70.8%	$ 1,201.9	76.5%	$ 1,143.9	72.8%	$ 89.0	8.0%	$ 31.0	2.8%
Core C&I	$ 205.5	13.1%	$ 193.4	12.3%	$ 214.3	13.6%	$ (12.1)	(5.9)%	$ 8.8	4.3%
NR A/C	$0.1	0.0%	$ 0.04	0.0%	$ 0.1	0.0%	$ (0.0)	(38.4)%	$ 0.00	6.6%
Gas Engine	$ 1.2	0.1%	$ 1.9	0.1%	$ 4.1	0.3%	$ 0.7	59.8%	$ 2.9	242.4%
NGV	$ 7.3	0.5%	$ 4.2	0.3%	$ 6.3	0.4%	$ (3.1)	(42.8)%	$ (1.0)	(14.3)%
Total Core	$1,332.6	84.8%	$ 1,401.5	89.2%	$ 1,374.3	87.5%	$ 68.8	5.2%	$ 41.7	3.1%
NonCore C&I	$ 77.1	4.9%	$ 45.6	2.9%	$ 64.3	4.1%	$ (31.5)	(40.9)%	$ (12.8)	(16.6)%
EG	$ 74.5	4.7%	$ 53.6	3.4%	$ 58.0	3.7%	$ (20.9)	(28.0)%	$ (16.50)	(22.2)%
EOR	$ 5.1	0.3%	$ 3.9	0.3%	$ 4.6	0.3%	$ (1.1)	(22.6)%	$ (0.5)	(10.0)%
Total Retail NonCore	$156.6	10.0%	$ 103.1	6.6%	$126.8	8.1%	$ (53.5)	(34.2)%	$ (29.8)	(19.0)%
Total WS & Intl	$ 46.3	2.9%	$ 37.2	2.4%	$ 34.6	2.2%	$ (9.1)	(19.6)%	$ (11.7)	(25.2)%
Total NonCore	$238.2	15.2%	$ 169.4	10.8%	$ 196.5	12.5%	$ (68.8)	(28.9)%	$ (41.7)	(17.5)%
Total System	$ 1,570.8	100.0%	$ 1,570.8	100.0%	$1,570.8	100.0%	$ 0.0	0.0%	$0.00	0.0%

Source: SoCalGas Workpapers on LRMC and Embedded Costs as revised October 2008.

Table 2
Summary Results of SoCalGas Base Margin Allocation Methods

[in $Mn and Percent Share By Customer Class]

Based on 79 Bcf Core Storage

Customer Class	DRA Recom. LRMC (NCO)	DRA As % of Total System	SCG Proposed EC	SCG EC as % of Total System	SCG Proposed LRMC (Rental)	SCG LRMC as % of Total System	Amt SCG EC> DRA	Percent SCG EC> DRA	Amt SCG LRMC>DRA	Percent SCG LRMC>DRA
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Residential	$ 1,117.7	71.2%	$ 1,204.5	76.7%	$ 1,148.5	73.1%	$ 86.8	7.8.%	$ 30.8	2.8%
Core C&I	$ 206.9	13.2%	$ 193.7	12.3%	$ 215.9	13.7%	$ (13.2)	(6.4)%	$ 9.0	4.4%
NR A/C	$ 0.1	0.0%	$ 0.0	0.0%	$ 0.1	0.0%	$ (0.0)	(38.3)%	$ 0.0	6.7%
Gas Engine	$ 1.2	0.1%	$ 1.9	0.1%	$ 4.1	0.3%	$ 0.7	58.2%	$ 2.9	240.1%
NGV	$ 7.4	0.5%	$ 4.2	0.3%	$ 6.3	0.4%	$ (3.2)	(43.1)%	$ (1.0)	(14.3)%
Total Core	$ 1,339.4	85.3%	$ 1,404.3	89.4%	$ 1,381.1	87.9%	$ 64.9	4.8%	$ 41.7	3.1%
NonCore C&I	$ 77.6	4.9%	$ 45.7	2.9%	$ 64.8	4.1%	$ (31.8)	(41.0)%	$ (12.8)	(16.5)%
EG	$ 75.4	4.8%	$ 53.9	3.4%	$ 58.9	3.8%	$ (21.5)	(28.6)%	$ (16.5)	(21.9)%
EOR	$ 5.1	0.3%	$ 3.9	0.3%	$ 4.6	0.3%	$ (1.2)	(23.0)%	$ (0.5)	(9.9)%
Total Retail NonCore	$ 158.1	10.1%	$103.6	6.6%	$ 128.3	8.2%	$ (54.6)	(34.5)%	$ (29.8)	(18.8)%
Total WS & Intl	$ 46.9	3.0%	$ 37.3	2.4%	$ 35.2	2.2%	$ (9.6)	(20.5)%	$ (11.7)	(24.9)%
Total NonCore	$ 231.4	14.7%	$ 166.5	10.6%	$ 189.7	12.1%	$ (64.9)	(28.1)%	$ (41.69)	(18.0)%
Total System	$ 1,570.8	100.0%	$ 1,570.8	100.0%	$ 1,570.8	100.0%	$ 0.0	0.0%	$0.00	0.0%

Source: SoCalGas Workpapers on LRMC and Embedded Costs as Revised October and November 2008.

Table 3

Summary Cost Allocation By Function ($Mn) For 70 Bcf

	Cust costs	MPD costs	HPD Costs	BB Trans costs	Local Trans costs	Stor Seasnl	Stor Load Bal	Non-DSM Mktg	Uncollectibles	NGV Comp Adder	Total Core	Total NonCore	Total System
NCO	$556.9	$ 457.4	$ 102.3	$ 20.0	$ 105.9	$ 39.3	$ 2.8	$ 36.4	$ 4.8	$ 1.3	$1,327.0	$ 243.8	$1,570.8
Rental	$786.5	$338.2	$ 75.6	$ 14.8	$ 78.3	$ 39.3	$ 2.8	$ 26.9	$ 4.9	$ 1.3	$1,368.7	$ 202.1	$1,570.8
EC	$945.9	$270.6	$ 28.5	$ 36.7	$ 36.1	$ 41.7	$ 3.8	$ 38.2	$ -	$ -	$1,401.5	$169.4	$1,570.8

Source: SoCalGas Workpapers for LRMC and Embedded Costs as Revised October 2008.

Table 4

Summary Cost Allocation By Function (As % of Total System) For 70 Bcf

	Cust costs	MPD costs	HPD Costs	BB Trans costs	Local Trans costs	Stor Seasnl	Stor Load Bal	Non-DSM Mktg	Uncollectibles	NGV Comp Adder	Total Core	Total NonCore	Total System
NCO	35.4%	29.1%	6.5%	1.3%	6.7%	2.5%	0.2%	2.3%	0.3%	0.1%	84.5%	15.5%	100.0%
Rental	50.1%	21.5%	4.8%	0.9%	5.0%	2.5%	0.2%	1.7%	0.3%	0.1%	87.1%	12.9%	100.0%
EC	60.2%	17.2%	1.8%	2.3%	2.3%	2.7%	0.2%	2.4%	0.0%	0.0%	89.2%	10.8%	100.0%

Table 5

Summary Cost Allocation By Function ($Mn) For 79 Bcf

	Cust costs	MPD costs	HPD Costs	BB Trans costs	Local Trans costs	Stor Seasnl	Stor Load Bal	Non-DSM Mktg	Uncoll ectibl es	NGV Comp Adder	Total Core	Total NonCore	Total System
NCO	$556.9	$ 457.4	$102.3	$ 20.0	$ 105.9	$ 44.9	$ 3.4	$ 36.4	$ 4.8	$ 1.3	$1,333.2	$ 232.1	$1,570.8
Rental	$786.5	$338.2	$ 75.6	$14.8	$78.3	$ 44.9	$ 3.4	$26.9	$ 4.9	$1.3	$1,374.9	$ 195.9	$1,570.8
EC	$945.9	$270.6	$ 28.5	$ 36.7	$ 36.1	$44.9	$ 3.4	$ 38.2	$ -	$ -	$ 1,404.3	$ 166.5	$1,570.8

Source: SoCalGas Workpapers for LRMC and Embedded Costs as Revised November 2008.

Table 6

Summary Cost Allocation By Function (As % of Total System) For 79 Bcf

	Cust cost s	MPD costs	HPD Costs	BB Trans costs	Local Trans costs	Stor Seasnl	Stor Load Bal	Non-DSM Mktg	Uncolle ctibles	NGV Comp Adder	Total Core	Total NonCore	Total System
NCO	35.4%	29.1%	6.5%	1.3%	6.7%	2.9%	0.2%	2.3%	0.3%	0.1%	84.9%	14.8%	100.0%
Rental	50.1%	21.5%	4.8%	0.9%	5.0%	2.9%	0.2%	1.7%	0.3%	0.1%	87.5%	12.5%	100.0%
EC	60.2%	17.2%	1.8%	2.3%	2.3%	2.9%	0.2%	2.4%	0.0%	0.0%	89.4%	10.6%	100.0%

III. DISCUSSION / ANALYSIS OF DRA RECOMMENDATIONS

SoCalGas describes itself as the largest natural gas distribution utility in North America, with over 2,700 miles of gas transmission lines, 131 BCF of storage inventory, and over 87,000 miles of gas distribution mains and services.[8] The physical configuration of SoCalGas' gas system is fully integrated and consists of underground storage fields, and a gas transmission system that serves both a backbone and local transmission function.[9] The SoCalGas distribution system is composed of both high- and medium-pressure systems. SoCalGas delivers gas to over five million retail customers over its backbone and local transmission system and its distribution system, and to four wholesale and one international customer.

SoCalGas has proposed a base margin of about $1.57 billion that it intends to allocate among its various customer groups in this proceeding. SDG&E, the co-Applicant in this proceeding, is an affiliate of SoCalGas and is also a wholesale customer of SoCalGas. Both SoCalGas and SDG&E are subsidiaries of their parent company Sempra Energy. DRA Exhibit 4 provides the analysis and recommendations for SDG&E.

A. Overview of SDG&E's and/or SoCalGas' Proposal

DRA's review of the proposed cost allocation is based on the Joint Applicant's Prepared Testimony and Errata in October 2008 as well as its workpapers, discovery responses, and clarifications received by the DRA by mail, email, and telephone conversations and relevant Commission decisions.

The current Commission-adopted cost allocation methodology for the SoCalGas base margin is the Long Run Marginal Cost (NCO). This methodology applies to the utility's base margin revenue requirement which is the basic gas transportation service revenue requirement including customer costs (including service lines and meter), distribution costs (including medium and high pressure),

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[8] Emmrich Testimony, p.18.

[9] D.06-04-033 approved the SoCalGas/SDG&E system integration.

and storage and transmission costs. The gas commodity cost is not part of the base margin. Regulatory accounts and other accounts outside the base margin but that are part of the utility's transportation revenue requirements, are referred to as "non-base margin." The other costs; such as, Energy Efficiency and Low Income programs, Self Generation Program, NGV Operation Program, gas acquisition expenses, and hazardous waste recovery costs are part of non-base margin, and hence, are also excluded from the scope of the cost allocation study because they are funded outside of base margin costs.[10]

SoCalGas proposes that the EC methodology be used to allocate all gas transportation base margin costs to customers since it is the "preferred" methodology.[11] SoCalGas is essentially requesting to change the current cost allocation methodology. SoCalGas also concurrently submits what it considers to be a "compliance" case as part of its application in A.08-02-001 based on the Commission's historical use of LRMC to allocate costs among customers.[12] The SoCalGas LRMC compliance case is based on the Rental method rather than the NCO method that was previously adopted in the SoCalGas/SDG&E BCAP decision in D.00-04-060. SoCalGas is therefore not consistent with D.00-04-060.[13] The Commission should reaffirm its adoption of the LRMC/NCO methodology, and therewith adopt DRA's recommendation, and order SoCalGas to modify its LRMC compliance filing accordingly.

The cost allocation issue in this application is two-fold: First, there is the question of whether or not the Applicants should continue to use the Commission-adopted LRMC/NCO cost allocation methodology to allocate all its base margin costs to customers, and if not, should the Commission adopt instead the LRMC/Rental methodology as the "compliance" case or the EC cost allocation

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[10] Emmrich testimony, p. 14.

[11] A.08-02-001 dated February 4, 2008, p. 7.

[12] Ibid.

[13] D.92-12-058 adopted LRMC methodology for the 3 gas utilities: PG&E, SoCalGas, and SDG&E. D.00-04-060 subsequently adopted the LRMC (NCO) for SoCalGas and SDG&E.

methodology “preferred” proposal of SoCalGas, or some alternative hybrid combination of the cost allocation methodologies as the “compliance” case. Second, the Commission needs to determine as the scoping memo states, “whether (or not) the updated cost allocations and rates are just and reasonable and should be adopted.”[14]

In discovery, DRA asked SoCalGas to also provide workpapers and results based on the LRMC/NCO approach. SoCalGas presents the results for both methods of the Commission-adopted LRMC and their preferred EC method for the cost allocation of all base margin costs to their customers. DRA notes that both the LRMC/Renta) method and EC method submitted by SoCalGas make use of the same gas storage capacity allocations for the gas storage function. The Settlement Agreement in Phase I of this proceeding (that is pending Commission approval) specified the EC method for the gas storage function for the duration of the agreement. It should be pointed out that the Commission effectively adopted a hybrid type of cost allocation for PG&E’s natural gas transportation business. PG&E has the LRMC/NCO method for the cost allocation of its natural gas distribution base margin, while the EC method is used for its transmission and gas storage functions. The latter was adopted pursuant to the original PG&E Gas Accord in 1997, and subsequent extensions, as approved by the Commission.[15]

The Commission should reject SoCalGas’ proposal and retain the LRMC/NCO method as recommended by DRA. SoCalGas has failed to prove that its’ proposed “compliance” or preferred methodologies are just and reasonable. Below, DRA explains each proposed methodology and the reasons why neither the “compliance” nor “preferred” cases are just and reasonable.

1. LRMC/Rental (Compliance Case)

The Commission first adopted the LRMC methodology to allocate SoCaGas’ base margin costs in D.92-12-058, and this has been the cost allocation method for

[14] See Ruling, p. 7.

[15] See original Gas Accord approved in D.97-08-055.

SoCalGas for the past 15 years. However, in this application, the Applicants claim that the adopted methodology that the Commission has been using for 15 years “no longer reasonably represents the true marginal costs of serving their customers.”[16] Ms. Allison Smith’s Direct Testimony on LRMC on behalf of SoCalGas states:

> SDG&E and SoCalGas believe that the Commission’s methodological evolution in its application of LRMC for cost allocation in BCAPs over the last 15 years has resulted in measures of cost that no longer reasonably represent the true marginal costs of serving their customers.

SoCalGas cites examples of how the Commission deviates from the utilities’ interpretation of LRMC efficiency principles.

First, SoCalGas cites the Commission’s adoption of the new Customer Only (NCO) method for marginal customer costs.[17] SoCalGas asserts that the NCO methodology does not capture all the underlying cost to serve all customers. According to SoCalGas, this results in requiring a much larger scale adjustment to achieve the utility’s revenue requirement and does not give efficient price signals to customers considering new hookups.[18] SoCalGas explains:

> The NCO method does not give efficient price signals to customers considering new hookups because the approach ensures that they will never pay the full costs incurred to hook up to the utility’s gas system. Other customers will always pick up the majority of those costs. This occurs because the NCO method takes the full cost per customer to hook up a new customer (not the annualized cost) and multiplies that value only by the average number of <u>new</u> customers to be added in that class. Therefore, this method (except where the growth rate of a customer class is very high) will significantly understate true marginal customer-related costs, thereby artificially lowering core rates.

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[16] Prepared Direct Testimony of Allison F. Smith in A.08-02-001 on SoCalGas LRMC as Revised October 2008, p. 3.

[17] Ibid.

[18] Ibid., p. 4.

Therefore, with regard to the derivation of its LRMC customer costs, SoCalGas supports the use of the rental method over the NCO method to calculate marginal customer costs.[19]

Second, SoCalGas asserts that "the inclusion of replacement cost adders in the marginal cost computation effectively moves the resulting costs farther away from true marginal costs."[20] The utility explains that since LRMC makes use of the Real Economic Carrying Charge (RECC) to annualize plant investment costs, the methodology already accounts for replacement costs, and thus, "adding in a separate and explicit adjustment for distribution replacement costs double counts these costs."[21]

Third, SoCalGas claims that "consumer groups have introduced "proxies" for transmission and storage resource plans in cost of service and BCAP proceedings."[22] SoCalGas alleges that "the Commission has included the costs of these proxies in rates, even though these proxies are not based on system requirements but have rather been included to justify shifting costs to the noncore class."[23]

In data responses to DRA, SoCalGas provides two additional examples of elements of the current LRMC methodology that are supposedly inconsistent with LRMC efficiency principles. According to SoCalGas, "The Commission adopted the 1-in-35 Peak Day Marginal Demand measure instead of peak hour in allocating medium pressure distribution costs." In SoCalGas' opinion, this is not consistent with marginal cost theory or cost causality.[24] Moreover, SoCalGas states that "The

[19] Ibid., p. 5.

[20] Ibid., p. 4.

[21] Ibid.

[22] Ibid. p. 5.

[23] Ibid.

[24] SoCalGas Response to DRA Data Request PZS7-1.

scaling of revenues up or down depending on the under collection or over collection of revenues…results in greatly fluctuating scaling."[25]

2. Embedded Cost (Preferred Case)

In lieu of the Commission-adopted LRMC, SoCalGas proposes that the Commission adopt the Embedded Cost methodology to allocate all base margin costs to its customers.[26] In advocating the use of the EC method of allocation, SoCalGas' witness Mr. Herbert Emmrich cites what he deems to be the advantages of the EC over the Commission-adopted LRMC. First, "Since these costs are recorded costs, they are objective and fully verifiable through review of SoCalGas' detailed accounting records."[27] Secondly, Mr. Emmrich claims that the EC method results in costs that are "closely aligned with SoCalGas' total revenue requirements as evidenced by the relatively small 1.8% reconciliation factor, compared to the larger 20% negative "scale" adjustment required in the SoCalGas' LRMC study."[28] Third, Mr. Emmrich asserts that "The average costs derived from this ECS (Embedded Cost Study) diverge less from proper marginal costs."[29] Fourth, SoCalGas states that the EC method is more easily understood by stakeholders because the "method is directly linked to recorded historical costs that are known and measurable."[30] And lastly, SoCalGas claims that nearly all gas distribution utilities and pipelines in the US utilize embedded costs.[31] In addition, SoCalGas also cites the FERC and the National Energy Board of Canada as both relying upon

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[25] Ibid.

[26] Prepared Direct Testimony of Herbert S. Emmrich in A.08-02-001 as Revised October 6, 2008 on Embedded Cost Allocation, p. 1.

[27] Ibid., p. 11.

[28] Ibid. p. 11

[29] Ibid.

[30] Ibid., p. 12.

[31] Ibid., p. 8.

EC principles for purposes of setting interstate and inter-provincial gas pipeline rates.[32]

B. DRA Discussion/Analysis

DRA first notes that SoCalGas does not dispute the economic theory on marginal cost. SoCalGas has no disagreement about the economic benefits of marginal cost-based pricing nor the soundness of the underlying economic theory on marginal cost.[33] SoCalGas, however, takes issue with the way the cost allocation method based on the academic marginal cost theory is currently implemented in the real world by the Commission.[34] SoCalGas contends that the current application of the LRMC has deviated from basic economic efficiency principles and "no longer reasonably represent the true marginal costs of serving their customers."[35] For the Commission to depart from its long standing 15-year approach, SoCalGas must demonstrate how and why LRMC/NCO no longer represents the true marginal costs of serving their customers. However, SoCalGas fails to prove its claim and therefore, the Commission should not adopt the proposed change in cost allocation methodologies.

The SoCalGas concerns on deviation from economic efficiency principles pertain to the proper marginal customer costs (the rental versus NCO), the appropriateness of replacement cost adders, the resource plans, and the impact of scaling to the utility's total revenue requirement. DRA agrees with SoCalGas that these maybe matters of serious contention in the current Commission-adopted LRMC methodology. However, the Commission has already addressed and concluded on these issues. In so far as the replacement cost adders for gas marginal costs are concerned, the Commission's findings in D.05-06-029 for the

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[32] Ibid., p. 9.

[33] Emmrich Testimony on EC, pp. 5-6.

[34] Ibid.

[35] Allison Smith Testimony, p.3

2005 PG&E BCAP bring some measure of closure to the issue. In that Decision, the Commission states in Findings Of Fact #14 and #15:

> Economic literature does not resolve whether replacement costs are appropriately included in long run marginal cost calculations.
>
> PG&E argues convincingly that replacement cost for distribution facilities are already recognized in marginal distribution costs.

And in Conclusion of Law #6, the Commission states:

> The calculation of marginal customer costs for gas service should not continue to include a value recognizing replacement costs of gas facilities.

DRA has previously supported the inclusion of replacement cost adders but will not pursue them further for the gas utilities in light of the Commission pronouncements in the 2005 PG&E BCAP. It has been DRA's position that if the replacement cost adder is rejected for the demand-related function, then for consistency purposes, this should also be removed from marginal customer costs.

Briefly, there is a basic difference of approach in how best to measure the cost imposed by the addition of a new customer. Under the NCO method, the new Service, Regulator, Meter (SRM) cost is multiplied by the projected number of new customers to come up with a new customer cost. This cost is a total investment for new customers only in a given year, rather than an annualized cost for the investment. Under a rental method, the Real Economic Carrying Cost (RECC) is used to develop an annualized cost for the investment. This annualized cost is charged to all customers. SoCalGas asserts that, since the NCO does not use an annualized cost, the RECC factors are not part of the calculation. This is the fundamental difference between the LRMC/NCO and rental methodologies.

SoCalGas was asked whether the rental method as used by SoCalGas necessarily assumes that all customers are renters of equipment from SoCalGas without any choice to purchase their own set of new customer hook up equipment. Further, DRA asked whether in SoCalGas' opinion, it would be realistic to assume that all customers are renters of equipment, and if not, to explain why the rental approach would make more sense than assuming that new customers could also purchase their own equipment. The SoCalGas response is given below:

> It does not matter whether a customer is a renter or an owner. The LRMC to each is the same and the rent charged to a renter of a house is equal to the cost that owners incur by not renting their house out and using it themselves. This is the opportunity cost principle of economics. In other words, if I own a house free and clear of any debts and use it for myself, it costs me the rent that I could have charged a renter if I had rented the house out.

The Commission originally adopted the rental method in its LRMC policy decision. Prior to the last SoCalGas BCAP decision, that method has subsequently been replaced by the NCO method for every major gas and electric utility except SoCalGas. With the adoption of the Joint Recommendation in D.00-04-060, the NCO was also adopted for SoCalGas.

There is a long history of Commission precedents that explain its preference for the NCO over the rental method. The Commission best explains the meaning of this fundamental difference in methodology in the last BCAP decision:[36]

> The proponents of the NCO method claim that the rental method is based upon an inappropriate theoretical foundation: a hypothetical competitive rental market with no opportunity to pay hookup charges or purchase the equipment. As a consequence, the rental method significantly overcharges customers.
>
> The proponents of the rental method claim that it is the NCO method which is fatally flawed because it is the rate of growth of a particular customer class which drives the marginal cost estimates. As an example, they point to the impact that the NCO method had on the gas engine class following our initial adoption of the NCO method in SoCalGas' last BCAP. Because the NCO method resulted in an 80% increase for this class, we elected to retain the rental method (D.97-08-062). These proponents believe the NCO method is theoretically incorrect, is not based on cost causation, and sends inaccurate price signals…

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[36] D.00-04-060, pp. 26-28.

> We then proceeded to analyze and reject each of these arguments finding: (1) that the NCO method fully comports with marginal cost pricing theory; (2) the rental method is premised on an assumption concerning opportunity value that does not hold for customer hookups; and (3) the rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market (Id., pp.403-404) In short, we considered and rejected each of the arguments being made in this proceeding…
>
> Finally, the issue was revisited yet again in SoCalGas' 1996 BCAP with both TURN and SDG&E proposing the NCO method and SoCalGas, ORA, and other intervenors supporting the rental method. The NCO method was again attacked on grounds that the rate of growth was the primary driver of the allocation and that small, rapidly growing customer classes could experience rate volatility. We adopted the NCO method finding that:
>
> The NCO method is preferable to the rental method as it improves both the price signal sent to the customer and costing accuracy. Parties have not presented any new evidence in this proceeding that causes us to change the conclusion we reached in PG&E's last BCAP, D.95-12-058, or Edison's GRC, D.96-04-050. (D.97-04-082, Slip Opinion, p. 59.)

In this proceeding, the Applicants have not presented any new factual evidence or arguments with respect to the NCO and rental methods, and therefore, for the same reasons expressed by the Commission in the last BCAP, DRA continues to support the NCO method. Additionally, DRA notes that the two LRMC approaches result in substantially different marginal customer costs. For example, the marginal cost for SoCalGas' residential customers is $84 per customer under the NCO approach and $155 per customer under the rental approach (2009$). The same holds true for the other customer classes, ie., the NCO cost is less than the rental cost per customer.

The LRMC/Rental method is further unjust and unreasonable because it would allocate about $230 million more to the core class than under the LRMC/NCO method for customer costs.[37] This makes a huge difference in terms of the marginal customer cost portion of the LRMC methodology. Marginal customer costs are allocated based on the number of customers, and with core comprising the majority of SoCalGas customers, then the core will get more of the marginal customer cost assigned to their class the greater those costs become.

In addition to the question of whether or not the total investment for new customers should be annualized, another source of past differences between the LRMC/NCO and LRMC/Rental arise from the estimates for the cost of the SRM and the forecast of customers and demand. In this proceeding, DRA does not take issue with the SoCalGas estimates of the SRM, and its forecasts of customers and demand.

There is No Empirical Evidence on SoCalGas Assertions of Price Signal Distortions

In this application, the underlying reason that SoCalGas justifies its proposal to replace the LRMC/NCO methodology is by claiming that the adopted methodology "no longer reasonably represent the true marginal costs of serving" its customers. SoCalGas' reasons for changing to the EC method are mainly alleged distortions resulting from the Commission-adopted LRMC and are not backed-up by empirical evidence. When asked about providing the specifics of the alleged distortions, SoCalGas states:[38]

> The use of the NCO method vs. the rental method of allocating customer costs is a prime example of providing customers distorted cost signals as indicated by Ms. Smith in her direct testimony. Therefore, all rates adopted since 1992 in D.92-12-058 have provided customers with distorted cost signals. All documents related to BCAPs since 1992 are available in Commission filings. All rates shown in the final BCAP decisions since 1992 therefore have provided distorted price signals to customers.

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[37] Refer to Tables 3 and 4.

[38] Refer to SoCalGas Response to DRA PZS1-2.

Since the rates shown in the final BCAP decisions reflect just the rates, and they do not by themselves necessarily demonstrate that they provide distorted price signals to customers, DRA pursued the matter further and asked SoCalGas to substantiate its assertion in the above response with evidence of such alleged price signal distortion. To explain its assertions of price distortions, SoCalGas states in a data response to DRA:[39]

> Rates in final BCAP decisions were based on a negotiated settlement not on economic efficiency therefore the rates provide distorted price signals. Economically-efficient price signals would mean rates are based on LRMC not negotiated rates in the BCAP process.

It is unreasonable for SoCalGas to expect the Commission to modify a long-standing cost methodology based on a speculative assertion. SoCalGas' assertion is difficult to validate because while all the rates adopted in previous BCAP decisions are documented, there is simply no adopted historical data that tracks the utility's so-called "true marginal costs" to enable the Commission to determine whether or not the adopted LRMC-based rates, or those that were the products of past negotiated settlements, deviate from the true marginal costs. Therefore, SoCalGas' claim is without merit.

SoCalGas should demonstrate how it measured or gauged the effectiveness of the current methodology against the utility's average intrastate rates. Economic theory would suggest that if the LRMC methodology were accurately translating into LRMC-based rates, those rates would provide effective price signals to customers that would guide natural gas consumption behavior.[40] Consequently, if those LRMC price signals were functioning effectively to inform the customer regarding the cost of the next additional therm of gas to be consumed, or the cost of the additional customer to be served, then those price signals would have enabled greater

[39] Response of SoCalGas to DRA PZS5-2.

[40] In D.95-12-053, the Commission states that it selected marginal cost pricing "because we found it would send the most accurate price signal to customers regarding how much gas to use and when to use it."

operational efficiencies to the utility through time, and which in turn, would have gradually translated into savings via declining long run average intrastate rates to customers. At least based on economic theory, that is how the price signals are supposed to function and translate into lower long term rates and ensure the efficient allocation of all available resources to the benefit customers over the long run.

There is now a 14-year record for the Commission to review the Commission-adopted LRMC performance record for SoCalGas. But DRA would not recommend such a review of average historic rates to determine whether LRMC performed well to achieve its goals because one could easily conclude that the LRMC contributed to lower rates when in fact the lower rates may be the result of natural monopolies merely enjoying economies of scale. But mainly, a review of the historic record will not necessarily determine whether the price signals from the Commission-adopted LRMC-based rates in fact translated into lower long run average rates to customers over time, as economic theory would suggest.

It would be an oversimplification to conclude that the declining utilities' average intrastate rates over the 14 year period are attributable solely to the effectiveness of the LRMC allocation methodology.[41] First, gas distribution utilities are natural monopolies by nature. As such, the utilities' long run average costs will tend to show a slightly declining trend over time. This is an inherent tendency of utility monopolies due to efficiency gains from increasing returns to scale, or economies of scale. So, even if the recorded 14-year average intrastate rates of SoCalGas exhibit a declining trend, there is no basis to conclude that the LRMC-based rates should be given exclusive credit for a declining trend in average rates over time. The SoCalGas average intrastate rate went down from $0.30 per therm in 1994 to $0.17 per therm in 2007, or about a 57 percent decline over the period in constant 2007 prices. During the same period, the SoCalGas gas volumes increased from approximately 8,757,580 Mth in 1994 to 9,502,953 Mth in 2007, or approximately 8.5 percent increase during the period, that helped drive down the

[41] DRA reviewed 15-year data on average intrastate transportation rates for the two utilities (SoCalGas, SDG&E) from 1993 to 2007 obtained as a Data Response to DRA by SoCalGas in A.07-12-006.

utility’s average intrastate costs. While significantly expanding output and capacity, SoCalGas’ total revenue requirement declined from $2.6 billion in 1994 to $1.6 billion in 2007 (in constant 2007 prices).

Second, DRA notes that over the same period, the gas commodity costs gradually became a greater proportion of the utilities’ total delivered cost of gas. The gas commodity cost is a separate cost that is not a part of the base margin nor of the calculation of the utility’s average intrastate rate. The increase in the percentage share of the gas commodity portion was significant enough to make the total delivered cost of gas trend upward, effectively obscuring the declining trend in the SoCalGas average intrastate rate. From about only 45 percent of SoCalGas’ total delivered cost of gas in the year 1993, the gas commodity gradually increased during the period to become the major portion of the total delivered cost of gas, rising to approximately 77 percent in 2007. It is not known whether this observed trend will continue in the future. These gas commodity costs are pass-through market-based rates thereby providing strong price signals to customers. With these market-based rates, the separate gas commodity portion bundled within the utility’s total delivered gas rates serve as competitive price signals that influence customer consumption behavior to use energy more efficiently. Customers were receiving price signals that basically sent the message that the incremental cost of the next therm of gas consumption would cost more than the last one. But, as shown in DRA’s review of the total delivered cost of gas, the price signals from bundled rates that show costs were trending up could very well have come from the market-based gas commodity portion which had become the major portion of the delivered cost. Whatever the source of the price signals, the customers thus far seem to be receiving them and responding accordingly.

For these reasons, one could argue that a review of historic average intrastate rates would be less meaningful to gauge the effectiveness of the current LRMC methodology for SoCalGas. Even SoCalGas acknowledges “It is impossible to determine with any precision how costs and rates would have been affected over the years had the Commission correctly used LRMC to allocate costs and thereby set rates."[42]

In the absence of any verifiable hard evidence to substantiate the price distortion assertions or the effectiveness of the current LRMC methodology, DRA cannot conclude that the Commission-adopted LRMC was a bad deal for customers, and hence, should be replaced. Neither has SoCalGas demonstrated why the LRMC/NCO should be replaced.

The Commission's Goals in adopting LRMC (NCO) Remain Important

Further, as explained below, DRA continues to support the LRMC/NCO methodology for SoCalGas for other equally important reasons.

First, the 2008 Energy Action Plan Update states:

> The state's energy policies have been significantly influenced by the passage of Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006.

With the implementation of AB 32, the reduction of natural gas consumption resulting from greenhouse gas emissions is an important element of successfully addressing the environmental issues of the day. Natural gas, a relatively cleaner fuel, is undoubtedly going to be a critical part of the solution. Greenhouse gas issues are very much intertwined with increasing energy efficiency, and hence, we can say that efficient natural gas consumption is more important than ever. Price signals are one of the best ways to achieve energy efficiency aside from the already existing and contemplated programmatic measures. The recent Commission decisions to expand the Energy Efficiency and Low Income Energy Efficiency programs in D.08-09-040 and D.08-11-031, respectively, underscore the importance of achieving the Commission's original goals in adopting LRMC. Therefore, the Commission's original goals in adopting LRMC are still relevant today:[43]

> First, economic efficiency dictates that rates be based on marginal cost, not embedded cost. Marginal cost reflects the cost incurred due to an additional unit of service

[42] SoCalGas Response to DRA Data Request PZS7-10.

[43] D.86-12-009, p. 13.

> being provided. Usage of the utilities' transmission and distribution system by each customer up to the point that the cost of the last unit's usage equals the benefit gained by the customer from that usage maximizes the benefit of the utilities' investment for all customers.

<u>Implementation Drawbacks Do Not Outweigh LRMC Benefits</u>

The implementation drawbacks of the LRMC pointed out by SoCalGas have not been shown to outweigh the benefits of the LRMC. As already explained, the concern relating to a separate replacement cost adder adjustment is already a non-issue in this proceeding. Further, the SoCalGas assertion that "consumer groups have introduced "proxies" for transmission and storage resource plans in cost of service and BCAP proceedings" is also a non-issue in this proceeding. DRA is not contemplating introducing any modification in the transmission and storage resource plans of SoCalGas or SDG&E in this BCAP.

Moreover, in the event that SoCalGas considers the marginal demand measure to be an important aspect of the inconsistency with marginal cost theory or cost causality, then SoCalGas has had ample opportunity to demonstrate the appropriateness of its opinion on the marginal demand measure ("MDM") for allocating medium pressure distribution costs. Ironically, SoCalGas does not challenge that distribution MDM in this proceeding. SoCalGas could have included a showing on that issue in its testimony or alternatively, it could file a separate application seeking to modify the Commission adopted MDM (of 1-in-35 Peak Day instead of peak hour) in allocating medium pressure distribution costs. DRA notes that in this very proceeding, the Applicants are requesting for adoption of the Commission adopted peak month as the local transmission service allocator.

Lastly, the SoCalGas argument pertaining to the "scaling of revenues that results in greatly fluctuating scaling", is another non-issue. Both the LRMC and EC methods use scaling to the extent that a reconciliation with the revenue requirement is necessary. Development of the storage revenue requirement is a good example. The LRMC marginal storage revenues have been scaled to match the storage revenues under the EC method. The scaling of revenues is for purposes of revenue requirement reconciliation and does not impact the relative cost burden for each customer class. Noting that demand elasticities are equal across customer classes, the revenue scaling process via the Equal Percent of Marginal Cost (EPMC) assigns any additional revenue requirement in direct proportion to the marginal cost revenues of each customer class. As the Commission states in D.00-04-060:[44]

> A scaling function is performed so that total revenue collected from the customers will meet the authorized gas revenue requirement. The ratio of the marginal cost revenue for each customer class versus the total system marginal cost revenue determines the EPMC scale. For example, if the core class is responsible for 80% of the marginal cost revenues, it will be allocated 80% of the revenue requirement.

In DRA's view, the LRMC/NCO implementation problems pointed out by SoCalGas have either become non-issues in this proceeding or have been resolved by alternative remedies, and therefore, do not diminish the advantages of the LRMC methodology.

The ability of the LRMC methodology to provide price signals is an important consideration. While the historical record of embedded costs may provide a good benchmark for a relatively short time period, it does not inform the consumer by way of price signals how much burden the customer's incremental future gas consumption will impose on the system, and therefore, will not help the customer purchase economically efficient levels of service. The Commission stressed the importance of price signals by stating:[45]

> It is our belief that accurate marginal cost methods will lead to clearer signals when marginal cost-based prices are implemented, thereby providing the opportunity for customers to purchase economically efficient levels of service.

No Change in Circumstances

SoCalGas' application fails to assert or show that circumstances for SoCalGas have changed substantially to warrant a switch from the LRMC allocation methodology. However, they do assert that a majority of states' gas utilities have

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[44] D.00-04-060, p. 97.

[45] D.92-12-058, p. 16.

now abandoned LRMC in favor of the EC method. The reasons for the apparent exodus from LRMC by gas utilities may have been reasonable for those particular utilities based on the particular circumstances of those utilities. But regardless, this does not mean that circumstances have changed such that the goal of providing price signals is less important today.

As the dynamics of market supply and demand for gas continue to evolve, we see that gas prices continue to climb. It is therefore important for utilities to continue to send the appropriate price signals to consumers on the consequences of incremental natural gas consumption on their part.

SoCalGas Proposal Not Shown to Provide Benefits to Core Customers

And finally, the SoCalGas preferred filing shows that the proposed EC will result in a greater cost burden on SoCalGas core customers compared to both LRMC methods. DRA's review shows that under the current LRMC/NCO method, the core customers will have approximately 85% share of the base margin while noncore customers will have approximately 15% share in this new BCAP period.[46] This is more beneficial to core customers than the results under the LRMC/Rental method. Under LRMC/Rental, core customers will have an 87.5% share of the base margin while noncore customers will have 12.5% share. On the other hand, under the proposed EC method, the core customers will have a greater share at 89.2% of the base margin while noncore customers will have a 10.8% share. Of the three methods, the proposed EC method will allocate the greatest share to the SoCalGas core customers. Therefore, the LRMC/NCO results in a clear financial benefit to SoCalGas core customers compared to those in both LRMC/Rental and the EC methods.

This is not to say that the EC cost allocation method adheres less to cost causation principles. Both methods are both anchored on cost causation principles. The primary difference between the two methods is that the EC relies on actual recorded cost of service while the LRMC relies on the incremental costs to provide the service. If one were to consider a one or two year time horizon, then EC could

[46] Based on 70 Bcf storage assumption.

also provide realistic price signals as they would likely not deviate significantly from actual recorded costs within only such short period.[47] On the other hand, if the utility were planning for the longer term, in theory the LRMC methodology would provide efficient price signals because the cost of future resources to meet additional demand are factored into the cost allocation.

Based on the foregoing, DRA recommends that the Commission adopt the LRMC/NCO methodology for the cost allocation of the SoCalGas base margin.

In the alternative, should the Commission favor adoption of the EC over the LRMC/NCO, the Commission should require SoCalGas to modify its proposed EC methodology to provide a more equitable allocation to customers. The Commission should only consider adopting the proposed EC cost allocation for all the base margin of SoCalGas if certain modifications are made that, at a minimum, provide for the same percentage share of cost allocation as the LRMC/NCO shown in this testimony, and include:

1. An allocation of 50% of A&G costs on the basis of average year throughput on equal cents per therm (ECPT);

2. An allocation of the remaining 50% of A&G costs based on O&M costs by using the Multi-factor, including functionalization for FERC Accounts 920 (A&G salaries), 921 (Office Supplies & Expense), 926 (Employee Pensions & Benefits), 931 (Rents), 408 (Payroll taxes), 932 (AdmGen Mnt-General Plant) and 389.1 thru 398 (General Plant depreciation) instead of the Labor Factor, and for functionalizing the general plant returns and taxes;

3. An update of the service line footage to reflect the latest 2006 data instead of the 2001 data used in the study

4. An update of the storage functional factors based on the most recent storage cost data in the 2007 FERC Form 2 instead of the old storage data used that is based on 2006 FERC Form 2 data;

5. Use of the Average Year Throughput as the allocator (instead of Cold Year Throughput) for the backbone transmission base margin for

[47] The Commission somehow recognizes this in Finding of Fact #57 in D.92-12-058 where it states "Generally, the marginal costs for transmission and storage are higher than the book-valued capital assets while marginal distribution and customer costs are quite close to embedded costs."

purposes of consistency with the allocator of the FAR revenue credits on transmission costs authorized in D.06-12-031 (FAR decision); and

6. Use of the historical embedded cost of meters represented by SoCalGas' net book value of meters as allocator (instead of the current purchased costs of meters) for customer-related O&M costs for distribution meters and regulators.

IV. DISCUSSION / ANALYSIS OF THE RESULTS OF THE UPDATED COST ALLOCATIONS

A. DRA Review of SoCalGas' LRMC (Rental) Proposal versus the NCO Method

The total Authorized Base Margin costs for allocation to SoCalGas' customer classes for 2008 are $1,571 million.[48] The 2008 base margin is comprised of approximately $952 million in O&M costs (roughly 60%), approximately $653 million (roughly 40%) in capital & tax-related costs (return, depreciation, income and property taxes and payroll taxes), approximately $64 million in miscellaneous revenues credit, and a Franchise and Uncollectible and reconciliation factor of $29 million. The amount of $29 million is indicated as the amount necessary to reconcile the 2007 base margin to the one authorized for 2008 (but final number will be determined in the SoCalGas/SDG&E General Rate Case proceeding). The goal in this BCAP proceeding is to allocate the base margin to the various customer classes based on the extent to which each customer class imposes a burden on the system. To achieve this under LRMC, the calculated marginal unit costs will be multiplied by the marginal demand measures (MDMs). The MDMs are the forecasts of throughput which drive the utility's investment decisions to meet anticipated demand.

The summary of results for each customer class are shown in Tables 1 and 2. Under LRMC/NCO and a 70 Bcf of core storage, the core customers will get allocated 84.8% of base margin while noncore customers will get allocated 15.2% of base margin. On the other hand, under LRMC/Rental, the core customers will get allocated 87.5% of base margin while noncore customers will get allocated 12.5% of

[48] Emmrich Testimony October 2008, p. 3.

base margin. Under a 79 Bcf of core storage assumption, the core customers will be allocated slightly more of the base margin, as shown in Table 2.

1. Marginal Demand Measures and Demand Forecast

SoCalGas updated the Marginal Demand Measures (MDMs) - number of customers, cold year throughput, peak month throughput, and peak day throughput - for the new BCAP period. The SoCalGas demand forecast is presented in Mr. Herb Emmrich's testimony who is also the witness for Embedded Costs. DRA's analysis of the SoCalGas demand forecast is presented in DRA Exhibit No.2. SoCalGas has separated the use of its transmission system into backbone and local transmission service. SoCalGas has proposed to allocate local transmission service on a peak month rather than a cold year throughput basis. Therefore, in the current application, SoCalGas has used different allocators for the backbone and local transmission. Backbone transmission is allocated based on Cold Year Throughput. Local transmission is allocated based on Peak Month Throughput.

DRA's review shows that the Embedded Cost and Long Run Marginal Cost studies use the same allocators for each function as shown in the Table below.[49]

Customer-related	# of customers
Medium Pressure Distribution	Peak Day Throughput
High Pressure Distribution	Peak Month Throughput
Transmission Backbone Local	 Cold Year Throughput Peak Month Throughput
Storage	Allocated capacities
Non-Energy Efficiency Cust Serv	Special study

However, DRA is not convinced that it is appropriate to use the same allocation factors used for the LRMC methodology, for purposes of allocation on

[49] Refer to SoCalGas Response to DRA PZS4-2.

an EC basis since the focus of the EC study is not on the marginal demand and costs. For example, the distribution and transmission systems actually serve a dual role, by serving not only peak day and/or month requirements but also supporting the daily needs of all customers. Therefore, DRA maintains that an alternative allocation of these costs under an EC allocation would be equitable and appropriate, such as a 50% allocation using average year throughput, and 50% using the peak day and/or peak month requirements. Given limitations of time and DRA's focus on its LRMC analysis for SoCalGas, it has not fully investigated the applicability of the allocators proposed by SoCalGas for its EC allocation and reasonable allocation options.[50]

2. Distribution costs

DRA does not take issue with the results of the LRMC/NCO and LRMC/Rental method for marginal distribution costs. DRA agrees with the methodology and the inputs to the regression model given the forecast demand growth for distribution.

Based on established LRMC methodology, SoCalGas developed the appropriate marginal unit costs for each functional category. These costs were then escalated to 2009 dollars to reflect SoCalGas' estimated marginal unit cost for the BCAP period. Lastly, these marginal unit costs were multiplied by the appropriate MDMs to obtain the total base margin cost revenues for each function. In the case of the distribution function, SoCalGas split distribution costs between as customer-related or demand-related.[51] The marginal cost for distribution consisted of three types of costs: capital-related, direct O&M, and indirect O&M. The indirect costs are included by applying the O&M loaders as

[50] For purposes of its EC analysis, DRA did use SoCalGas' proposed EC allocation factors but in doing so does not necessarily accept the reasonableness of these factors and may offer or support other allocation options at a future date.

[51] As established in D.92-12-058.

later explained. Further, SoCalGas developed separate marginal costs for medium pressure distribution (MPD) and high pressure distribution (HPD).[52]

The marginal cost for both an MPD and HPD consists of an annualized capital-related cost and the fully-loaded marginal O&M cost. SoCalGas used the standard linear regression model to develop the capital-related marginal MPD cost. The regression model uses the cumulative peak-day demand growth as the independent variable and the cumulative load-growth-related capital investment in the MPD system as the dependent variable. SoCalGas indicates that the load-growth-related investment includes new business, pressure betterment and meter and regulating station investment. The analysis period for the regression analysis is 15 years: 10 years of historical data (1997 – 2006) and 5 years of forecast data (2007 – 2011). The resulting estimated coefficient of the independent variable represents the capital-related MPD marginal cost. DRA agrees with the methodology and the data used as inputs.

The marginal O&M costs for the MPD system include direct O&M costs and O&M loaders. The year 2007 recorded direct distribution O&M costs are allocated between medium-pressure and high-pressure systems based on the split in total distribution investment between the medium and high-pressure distribution systems.

The Marginal cost for the SoCalGas HPD was similarly developed. The coincident peak-month demand served off of the HPD system is used as the measure of customer load for the HPD system.[53]

Overall, the LRMC/NCO method results in a slightly higher cost allocation for core and noncore customers in terms of the share of the distribution function in the base margin. As shown in Tables 3 and 4, under LRMC/NCO, the

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[52] The Commission acknowledged in D.92-12-058 that it is appropriate for SoCalGas to do this

[53] Based on previous BCAPs, and consistent with D.92-12-058 methodology.

distribution costs (combined MPD and HPD) are allocated approximately 35.6% of the scaled base margin whereas under LRMC/Rental these are allocated approximately 26.3% of the same. By comparison, under the proposed EC, the distribution costs allocated to core customers would be 19.0% of the base margin costs. DRA would attribute this difference in allocations to the way the costs have been functionalized in the proposed EC methodology as discussed in that section. The MDMs that serve as allocator for distribution costs are the MPD peak day demand and the HPD peak month demand.

3. O&M Loaders

The three O&M loaders are as follows: the A&G loading factor, the general plant loading factor, and the materials and supplies (M&S) loading factor. These O&M loading factors were also used in previous BCAPs. DRA does not take issue with the results of the direct O&M costs and the O&M loaders used in the LRMC/NCO and LRMC/Rental calculations.

In developing the A&G loading factor, the recorded year 2007 A&G expenses have been classified as either marginal or non-marginal on an account-by-account basis. SoCalGas indicates that any costs that vary with either the size of labor force or the size of plant were classified as marginal costs. The proposed A&G loading factor (including payroll tax loader) is 30.48%.

SoCalGas calculated a weighted average RECC factor for gross general plant and then applied that factor to gross general plant in service as of December 31, 2007 to derive an annualized cost for general plant. This annualized general plant cost was divided by year 2007 net O&M expenses to derive the general plant loading factor. The proposed general plant loading factor based on year 2007 recorded data is 16.44%

To develop the M&S loading factor, SoCalGas used recorded year 2007 M&S costs and allocated them based on gross gas plant in each functional category. Distribution M&S was further categorized as customer-related and demand-related distribution plant investment. The functionally allocated M&S

costs are annualized using an RECC factor, 12.97%, developed for M&S investments. The annualized M&S costs are then added to the marginal O&M costs for each function as part of the fully-allocated O&M costs.

4. Customer-related costs

Customer-related marginal cost reflects "the cost of a customer's access to the gas utility's supply system"[54] The marginal customer cost is comprised of: (1) the marginal capital cost of service, regulators and meters (SRM) and exclusive-use facilities; and (2) the marginal O&M costs associated with SRM, Customer Services, and Customer Accounts. SoCalGas based their estimates on updates of the unit costs from purchase records of various meter sizes, types, and pressure levels. For service lines, the service line lengths, pipe types, and pipe diameter data, at the customer level, were extracted from SoCalGas' service history file.

DRA's review indicates that the average number of new customers in the period 2001-2007 were approximately 68,000 customers.[55] For this BCAP, the forecast number of new customers is approximately 78,944.[56] Core customers account for 99.98% of all SoCalGas customers. In the last 7 years since 2000, new customers have been added to the system at the rate of 1.3% a year on average. The forecast in this BCAP would increase new customers by 16% above the 2001-2007 average. DRA understands that the customer forecast is reasonable since it should be consistent with those used in the last SoCalGas GRC.

The average cost per hook up during the 2001-2007 period was about $1,123 per new customer.[57] In this proceeding, the one time hook-up cost under the NCO method is estimated to be $1,228 on average for the residential class, an estimate which is close enough to the estimated hook-up cost in the year 2007.[58] DRA

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[54] See D.92-12-058, p. 38.

[55] Refer to SoCalGas Response to DRA PZS1-11.

[56] SoCalGas LRMC NCO workpapers.

[57] Ibid.

[58] SoCalGas LRMC NCO workpapers.

agrees with the SoCalGas customer investment cost estimates as well as the marginal O&M costs associated with the customer hook-up costs. As discussed in this testimony, it is the basic difference in the customer cost portion of the methodology between the LRMC/NCO and rental methods that results in a substantial difference in the cost allocation for core customers.

SoCalGas updated customer-class-specific O&M costs using year 2007 recorded O&M expenses. SoCalGas developed O&M loaders and applied them to the direct O&M costs to derive fully-loaded O&M costs.[59]

The combination of marginal capital costs and the fully loaded customer-related marginal O&M costs form the total customer-related marginal cost for each customer class.

Overall, DRA's review indicates that under the LRMC/NCO, approximately 36.4% of scaled total base margin costs are allocated to customer –related costs whereas under the LRMC/Rental, about 50.3% are allocated to customer-related costs. By comparison, the proposed EC method will allocate approximately 60% of the base margin to customer-related costs. The MDM that serves as the allocator for the marginal customer costs is the number of customers in each class.

5. Storage Costs

For purposes of this BCAP, the 4 Bcf of storage cushion gas was included in total storage capacities. SoCalGas clarified that the 4 Bcf of inventory associated with the Cushion Gas project is part of the total storage capacities for SoCalGas, which are reflected in the allocation of costs shown in their testimony.[60] This 4 Bcf of inventory capacity is part of the allocation of storage assets to the various functions – Core Seasonal Storage, Load Balancing, and the Unbundled Storage program. No special treatment was proposed for this capacity in this BCAP.

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[59] The SoCalGas customer-related marginal O&M costs consist of five components: 1) Customer Services, 2) Customer Accounts, 3) Meters and Regulators, 4) Service Lines, and 5) O&M Loaders. SoCalGas indicates that the first four components comprise the total direct O&M costs.

[60] Refer to SoCalGas Response to DRA PZS4-8.

The storage marginal cost was developed also on the basis of the total investment method. The SoCalGas witness for storage is Mr. Watson, who developed a 15-year resource plan for SoCalGas. Mr. Watson's storage resource plan includes the following capital investment: $6 million for inventory, $48 million for injection, and no investment for withdrawal. Mr. Watson further states that there will be no incremental O&M costs for any of the projects identified in his resource plan. Since there is no planned incremental investment for withdrawal, the marginal cost of withdrawal is presented based on the avoided cost methodology previously used by SoCalGas for storage functions when no capital investment was planned for that function.[61] DRA understands that even if these capital investments are included in these resource plans that are made part of LRMC calculations, the utility does not necessarily commit to actually making these capital investments. SoCalGas clarified that these resource plan forecasts are not actual forecasted budgeted spending.[62] SoCalGas states that storage resource plans are only best guess-estimates:[63]

> The storage resource plan represents a best-guess estimate of the costs to expand storage capacities assuming sufficient long-term contract demand in the unbundled storage program exists to warrant such expansions. The per-unit cost of these storage expansions depends upon size of the expansion, which is unpredictable.

SoCalGas and SDG&E clarified that they use the demand forecast in conjunction with customer requests for service and contractual obligations in the planning and expansion of its transmission, distribution, and storage systems.[64] The proposed Settlement Agreement addresses the future expansion of the gas storage assets. In the proposed SA, SoCalGas agrees to make commercially

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[61] SoCalGas states this is the same methodology it used in the 1999 BCAP.

[62] Refer to SoCalGas Response to DRA PZS1-11.

[63] Refer to SoCalGas Response to DRA PZS1-3.

[64] Refer to SoCalGas Response to DRA PZS5-3.

reasonable efforts to expand its storage inventory at its four existing storage fields by 7 Bcf over the period 2009-2014.[65] Likewise, SoCalGas agrees to expand injection capacity at its Aliso Canyon storage facility that is expected to expand injection capacity by about 145 MMcfd. If approved by the Commission, then any expansions during the term of the SA will occur under the EC method. Since the EC method uses historical costs, no storage resource expansions are included in the EC calculations in this proceeding. DRA's review indicates that the LRMC storage calculations (under both NCO and rental) include a 1 Bcf incremental capacity for inventory that would require a capital cost $6 million. The LRMC method provides an indication of how a future 1 Bcf incremental increase in storage inventory capacity will impact cost allocation for the different customer classes. Further, the LRMC storage calculations include a 150 MMcfd of incremental injection capacity that would require a capital cost of $48 million. But to the extent the LRMC compliance case filed by SoCalGas uses the EC assignment of storage capacities and the costs for the gas storage function calculations and scales down those LRMC storage-related costs to the same amounts as those under the EC method, the additional cost imposed by the incremental increases in capacity are not reflected in the results of either LRMC/NCO or rental method. In short, the storage cost allocations under both LRMC methods and the EC are expected to be the same.

Should the Commission adopt the Settlement Agreement in Phase I of this BCAP, the cost allocation of the gas storage function will be based on embedded cost for the duration of the Settlement Agreement. The Commission should order SoCalGas to update the proposed cost allocation methods based on the combined core portfolio storage amounts pursuant to a Commission approval of the Settlement Agreement in BCAP Phase 1 of this proceeding. Should the Commission continue to adopt the LRMC/NCO method for the remainder of the SoCalGas base margin in Phase II of this proceeding, SoCalGas will have a cost allocation for its transmission and distribution based on LRMC/NCO. This approach is somewhat similar to that used by PG&E, i.e., it uses embedded costs for the gas storage function and the

[65] See ALJ Wong's PD of Nov.4, 2008 that describes the SA provision.

LRMC for transmission and distribution functions, except that in PG&E's case, both transmission and storage are based on embedded costs while only the distribution function uses the LRMC/NCO method. The hybrid system has worked well for PG&E since the PG&E Gas Accord was first adopted in 1997 and subsequently extended.

6. Transmission

A separate transmission study (presented in Mr. Schwecke's testimony) shows that 57% of the integrated transmission system should be classified as Backbone Transmission and 43% should be classified as Local Transmission. Based on the 57%/43% split of Backbone and Local Transmission, the transmission resource plan has also been developed separately for each category. The marginal costs were also developed separately for the Backbone and Local Transmission.

SoCalGas uses the total investment method to determine the capital-related marginal transmission cost. Under the Total Investment Method, the cumulative transmission investment required to meet demand growth over a 15-year period is used to determine the capital-related marginal cost. The 15-year transmission resource plan presented by Mr. Bisi states that no capital investment is required on the Backbone transmission system to meet the expected incremental demand growth over the next 15 years. DRA notes that since 1992, SoCalGas has made substantial amount of capital investments to increase capacity on its backbone transmission system.[66] However, based on the demand forecasts reviewed by DRA's witness in this proceeding and Mr. Bisi's assessment that SoCalGas has sufficient capacity to meet such demand forecast, DRA does not take issue that no capital investment on the backbone is necessary. The adequacy of backbone transmission capacity is shown in Tables 1 through 3 of Mr. Bisi's testimony.[67]

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[66] Refer to SoCalGas Response to DRA Data Request PZS2-21b.

[67] Refer to Mr. Bisi's Testimony, pp. 5-6

For SoCalGas' Local Transmission system, Mr. Bisi has identified two capital projects with a total investment of $91.4 million.[68] Again, based on the demand forecasts which were reviewed and found reasonable in DRA's Exhibit 2 and Mr. Bisi's assessment of the sufficiency of capacity under the 1 in 35 year cold day design but not under the 1 in 10 year cold day scenario, DRA does not take issue with the estimated additional local transmission investment. The need for local transmission investment is shown in Tables 4 and 5 of Mr. Bisi's testimony.[69]

The Transmission marginal cost consists of an annualized capital-related cost component and a marginal O&M cost component. The marginal O&M cost for the transmission system includes direct O&M costs and O&M loaders. The recorded direct transmission O&M cost for 2007 is $53.2 million. The transmission marginal cost O&M cost reflects the total transmission O&M costs in FERC accounts 850-867, excluding compressor fuel and hazardous waste costs, which are not part of the authorized base margin. To develop the separate marginal costs for Backbone and Local Transmission, this direct O&M cost was split 57%/43%, as discussed above. The direct transmission O&M cost is then loaded with A&G, General Plant and M&S to determine the fully-loaded transmission O&M cost.

B. DRA's Review of the SoCalGas Embedded Cost Proposal

1. Summary

DRA has reviewed SoCalGas' Embedded Cost proposal. In the event that the Commission favor adoption of the embedded cost methodology, DRA recommends the following modifications in order to provide a more equitable allocation to customers:

[68] The LRMC calculations used a capital cost escalator applied on the $91.4 Mn cost to bring the amount to 2009 price level of $93.63 Mn as shown in SoCalGas LRMC workpapers.

[69] Ibid. pp. 6-7.

(a) That 50% of the A&G costs be allocated on an equal cents per therm (ECPT) basis. SoCalGas fails to present a detailed, accurate A&G study that clearly establishes the specific cost drivers for the A&G costs as the A&G factors contemplated by SoCalGas suggest. Absent such a detailed A&G cost study, DRA recommends that 50% of A&G costs be allocated on ECPT basis.

(b) That the remaining 50% A&G costs be allocated based on the O&M costs by using the SoCalGas Administrative & General (A&G) Multi-Factor, including those used for the functionalization of FERC Accounts 920 (A&G salaries), 921 (Office Supplies & Expense), 926 (Employee Pensions & Benefits), 931 (Rents), 408 (Payroll taxes), 932 (AdmGen Mnt-General Plant) and 389.1 thru 398 (General Plant depreciation) instead of the Labor Factor, and for the general plant returns and taxes;

(c) That the service line footage be updated using the latest 2006 data instead of the 2001 data presented in the SoCalGas testimony;

(d) That the storage functional factors be updated using the most recent storage cost data for the 2007 FERC Form 2 information instead of the previous storage data used for the 2006 FERC Form 2 information;

(e) That the Average Year Throughput be used (instead of Cold Year Throughput) to allocate the customer-related costs for the backbone transmission base margin to the different customer classes for purposes of consistency with the allocator of the FAR revenue credits on transmission costs authorized in D.06-12-031 (FAR decision); and

(f) That the historical embedded cost of meters represented by SoCalGas' net book value of meters be used (instead of the current purchased costs of meters) to allocate customer-related O&M costs for distribution meters and regulators.

2. Distribution Costs

Similar to the LRMC that recognizes that the distribution function has a customer –related and a demand-related function, the proposed EC allocates the distribution O&M costs between customer-related and demand-related. The functionalization of customer-related costs are based on a determination by SoCalGas' distribution staff experts.[70] A portion of distribution O&M is directly allocated as customer-related costs while the demand-related portion is further allocated between medium-pressure and high-pressure based on the percentage the distribution main footage. SoCalGas describes how O&M costs were functionalized and allocated under the EC approach:[71]

> For O&M expenses, SoCalGas analyzed costs by FERC account, and by sub-account, for purposes of functionalizing these expense elements. The analyses were guided in part by the manner in which SoCalGas functionalized its associated plant. Wherever possible, direct assignments to a particular function were made in a manner consistent with SoCalGas' treatment of plant. Then, based on a review of distribution costs, SoCalGas determined that in some cases, the use of installed footage (for each sub-function) was appropriate to functionalize the remaining O&M expenses. Inherent in this approach is that the unit O&M expense level is the same between sub-functions within a particular function; e.g., between high and medium pressure distribution. SoCalGas considers this approach to be reasonable considering that certain field personnel are performing similar activities for service lines and distribution mains with the expenses recorded in the same account.

The basis for the direct allocation of distribution O&M accounts to customer-related costs are the SoCalGas special studies conducted by its distribution staff experts. None of the distribution staff studies were provided in this proceeding, and hence, DRA has no opinion on the conclusions derived from those studies by SoCalGas' distribution experts. Overall, based on the determination of its distribution experts, the distribution O&M expenses under the proposed EC method indicates approximately 75% is classified as customer-related distribution while the remaining 25% (both MPD and HPD) is classified as demand-related distribution.

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[70] Emmrich Testimony, p. 34

[71] Ibid., pp. 19-20.

3. Administrative & General (A&G) Costs

SoCalGas did not conduct a detailed cost analysis for the A&G costs. Its witness Mr. Herb Emmrich describes the type of treatment for the A&G costs under its EC proposal:[72]

> Since not all costs can be simply assigned by a single factor, a compound allocation factor using two or more generalized allocation factors were combined together in recognition of the multiple bases upon which a particular cost element should be assigned to the various functions, cost classification categories, or classes of service contained in the cost study. This type of allocation factor recognizes that there is more than one cost driver that best captures the characteristics and activities of that cost element. The treatment of A&G expenses is a good example of this concept. Since these expenses are broad-based in nature and support a wide range of utility activities, the entire groupings of accounts, or certain specific accounts, were allocated on the basis of the combination of two or more generalized allocation factors. Portions of SoCalGas' and SDG&E's A&G expenses are treated in this manner,

The proposed EC makes use of several A&G factors for the functionalization of the base margin arising from A&G costs that amount to over $337 million. These A&G factors as described in Mr. Emmrich's Testimony are the Labor Factor, the O&M factor, the Net Plant Factor, and the Multi-factor (the average of the first three factors).[73] The functionalization of the A&G costs is further described by SoCalGas:[74]

> SoCalGas reviewed each of the twelve A&G accounts and compiled details on the nature of the activities and related costs contained in each account. This detail enabled SoCalGas to derive a functionalization factor for each account based on the predominant cost element(s) in each account.

[72] Ibid., p. 16.

[73] Emmrich Testimony, pp. 20-22.

[74] Emmrich Testimony, p. 21.

DRA is concerned with the use of these A&G factors since it assumes that these A&G costs that are broad-based in nature and support a wide range of utility activities can somehow be traced back to specific cost drivers such as those relating to the number of employees, the O&M costs, the net plant values, and if none seems close enough as a cost driver, then to a combination of all cost drivers when the multi-factor is used. These cost drivers under the EC proposed A&G factors will functionalize approximately 66% of the A&G costs as customer-related. In this proceeding, none of these A&G costs have been shown to be specifically linked to these cost drivers. SoCalGas has not presented a detailed study of these A&G costs to support the functionalization based on the A&G factors suggested by its testimony. Absent a detailed and accurate A&G cost study, there is no basis for DRA to determine whether or not these A&G costs are being attributed to the appropriate A&G factors. DRA therefore recommends that 50% of the A&G costs be allocated on ECPT basis. This DRA proposal is consistent with the prior Commission adopted policy and methodology pertaining to the allocation of A&G costs under an embedded cost allocation method. The Commission states in D.86-12-009:[75]

> A&G expenses are generally not broken into functions and classifications. Unfortunately, the staff, the utilities, and some other parties have simplistically classified these costs on the same basis as operations and maintenance (O&M) expenses are classified without providing any evidence that A&G costs are incurred on a similar basis as O&M expenses…We will adopt a compromise…50% of A&G expenses will be classified as commodity-related and allocated on an equal cents per therm basis, and 50% will be classified in the same manner as O&M expenses. This compromise reasonably balances the uncertainties in the classification of A&G expenses.

For the remaining 50% of A&G costs, DRA recommends that they be allocated using the A&G Multi-factor as presented in SoCalGas' testimony since all

[75] D.86-12-009, p. 25.

of the O&M costs are represented by the multi-factor (it is the simple average of the Three (3) A&G factors presented by SoCalGas.

4. Customer Costs

DRA's review indicates that under the proposed EC methodology, core customers will be allocated a greater share of the customer-related SoCalGas base margin compared to either the LRMC/NCO or LRMC/Rental. The proposed EC methodology will allocate about $389 million more customer costs to core customers compared to the LRMC/NCO methodology. [76] The proposed EC allocates approximately $159 million more customer costs to core customers compared to the LRMC/Rental methodology. The greater amount of customer-related costs allocated to core customers under the proposed EC can be traced back from the functionalization of the base margin costs where approximately 60 percent of the $1.5 billion base margin is classified to the customer-related function. The customer-related costs of the base margin amount to approximately $946 million under the proposed EC. Since the allocator for the customer-related costs is based on the number of customers in each class, and given that the core customers outnumber the noncore customers, then the majority of the $946 million classified as customer-related costs would be allocated to core customers under the proposed EC. These proposed EC allocators to customer classes for customer-related costs are based on the percentage share of each class in the cost of new meter purchases, service line lengths dedicated to the class, customer account numbers, historical cost of meters, distribution O&M costs, number of customers, and PACER volume and hours. These proposed allocators are predominantly core customers by sheer volume. All these proposed EC allocators suggest that core customers cause nearly all of the base margin costs and ensure that these costs are assigned to their class. DRA disagrees that all these proposed EC allocators for customer-related costs are appropriate. For instance, using the percentage share of each class in the cost of new meter purchases to allocate customer O&M would necessarily assume that all customers purchase new meters. In reality, that is not the case since only a

[76] Refer to Table 3 and 4 in this Testimony.

very small percentage are new customers in a each year. DRA will not provide a review of each proposed allocator since the proposed EC methodology is not being recommended by DRA.

5. Storage

The proposed EC would allocate the same percentage share of storage costs as the proposals under the LRMC/NCO and LRMC/Rental methods. This is because the storage costs under SoCalGas LRMC proposal are scaled down to exactly match those in the proposed EC and are based on the same gas storage capacity reservations. DRA's review shows that under a 70 Bcf combined core storage assumption, the proposed EC will allocate about $47.8 million to the combined core storage reservation for SoCalGas and SDG&E, $10.2 million for the balancing function, and about $29 million for the unbundled storage program.[77] On the other hand, under a 79 Bcf combined core storage assumption pursuant to the Settlement Agreement in Phase I, the proposed EC will allocate approximately $51.1 million to the combined core storage reservation for SoCalGas and SDG&E and approximately $25.6 million for the unbundled storage program, and $10.2 million for the balancing function.[78] DRA understands that the SoCalGas storage calculations in the proposed EC are based on the storage cost analysis of FERC Form 2 2006 recorded amounts rather than those in 2007 to match the updated 2007 data. The data used in the storage cost by product analysis should be updated if the proposed EC approach is adopted.

6. Transmission

The transmission base margin costs are functionalized 100 percent to the transmission function. Similar to the LRMC, the allocators used for the transmission costs to the different customer classes under the proposed EC are cold year throughput (for backbone) and cold year peak month (for local transmission). DRA's only concern with the transmission cost allocator is its inconsistency with the allocator for the transmission revenue Firm Access Rights credits. In the FAR

[77] SoCalGas Data Response to DRA PZS12-1.

[78] SoCalGas Embedded Cost Workpapers as Revised November 2008.

decision, the Commission approved the average year throughput to allocate FAR transmission credits.[79] If the proposed EC methodology were to be adopted, the proposed EC allocator for the transmission costs to the different customer classes should be made consistent with that used in the FAR decision.

7. DRA Modifications to the SoCalGas EC Proposal

The Table below presents the estimated impact of DRA's proposed modifications to the SoCalGas Embedded Cost proposal under a 79 Bcf core storage reservation:

Table 7
Allocation of Base Margin by Customer Class

Customer Class	Embedded Cost Allocation ($ Millions)	Average year Throughput (MDth)	Cents/Therm	Percent of Total Cost
Residential	$1,105.5	2,484	$0.445	70.4%
Core C&I	$192.2	971	$0.198	12.2%
Gas AC	$0.1	1	$0.049	0.0%
Gas Engine	$2.1	18	$0.115	0.1%
NGV	$6.1	117	$0.052	0.4%
Total Core	**$1,305.9**	3,591	$0.364	83.1%
Non-Core C&I	$69.3	1,440	$0.048	4.4%
Electric Generation	$102.5	2,827	$0.036	6.5%
EOR	$6.8	156	$0.044	0.4%
Total Retail Non-Core	**$178.6**	4,423	$0.040	11.4%
Wholesale & International				
Long Beach	$4.7	117	$0.040	0.3%
SDG&E	$49.0	1,227	$0.040	3.1%
Southwest Gas	$3.1	82	$0.038	0.2%
Vernon	$4.0	116	$0.035	0.3%
DGN	$2.0	54	$0.037	0.1%
Total Wholesale & Inter.	**$62.9**	1,596	$0.039	4.0%
TBS Storage	**$23.5**	N/A		1.5%
Total Base Margin	**$1,570.8**	9,611	$0.163	100.0%

[79] Commission decision in the Firm Access Rights proceeding D.06-12-031, p. 92.

IV. CONCLUSIONS

Based on the foregoing, DRA respectfully requests the Commission adopt the above recommendations.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
PEARLIE Z. SABINO

Q.1. Please state your name and business address.

A.1. My name is Pearlie Sabino. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the State of California at the California Public Utilities Commission (CPUC) as a Regulatory Analyst in the Division of Ratepayer Advocates (DRA).

Q.3. Please describe your educational background and professional experience.

A.3. I have an M.A. in Economics from Ateneo de Manila University and a B.S. in Business Economics from the University of the Philippines. I graduated from the Executive Training Program in Energy Planning and Policy of the University of Pennsylvania. I have worked for 19 years with the largest electric utility in the Philippines in various professional capacities in the areas of economic research, marginal cost studies, project evaluation, corporate budgeting and monitoring, and project financing.

I joined the Commission staff in 1997. In the last 11 years, I have worked on a number of electric and natural gas matters including but not limited to the following: the review of utilities' gas supply plans in the procurement proceeding, SoCalGas' Gas Cost Incentive Mechanism, the review of BCAP applications, various gas transportation contracts (such as Guardian, Ruby, US Gypsum), the SoCalGas/SDG&E system integration and firm access rights proceedings, the Joint SCE/SoCalGas/SDG&E Omnibus proceeding, and the Joint Application for Public Purpose Program Cost Reallocation proceeding.

Q.4. What is your area of responsibility in this proceeding?

A.4 I am sponsoring DRA Exhibit No.3, which is DRA's Direct Testimony in A.08-02-001 Phase II on cost allocation issues for SoCalGas.

Q.5 Does this complete your testimony?

A.5 Yes, it does.

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